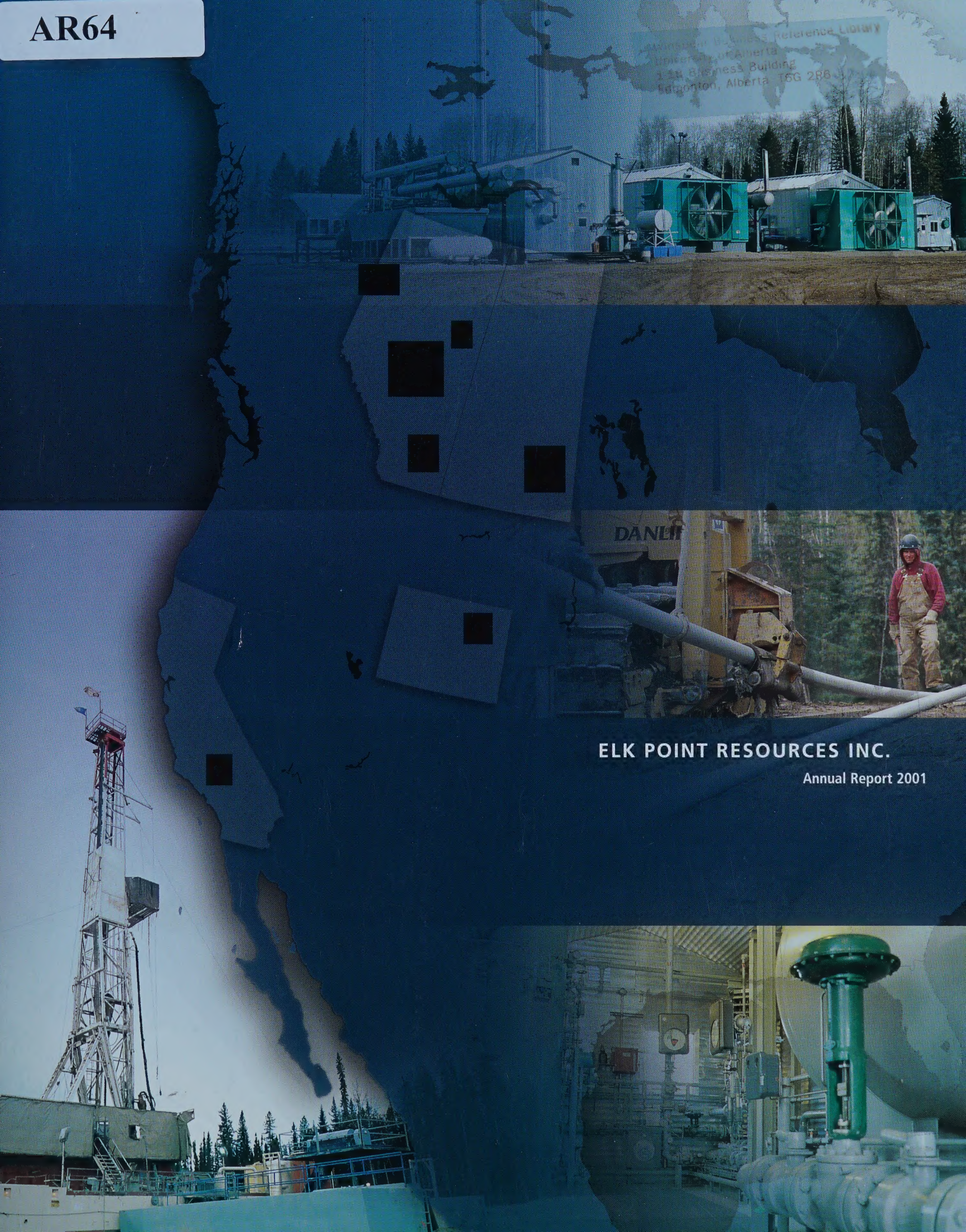
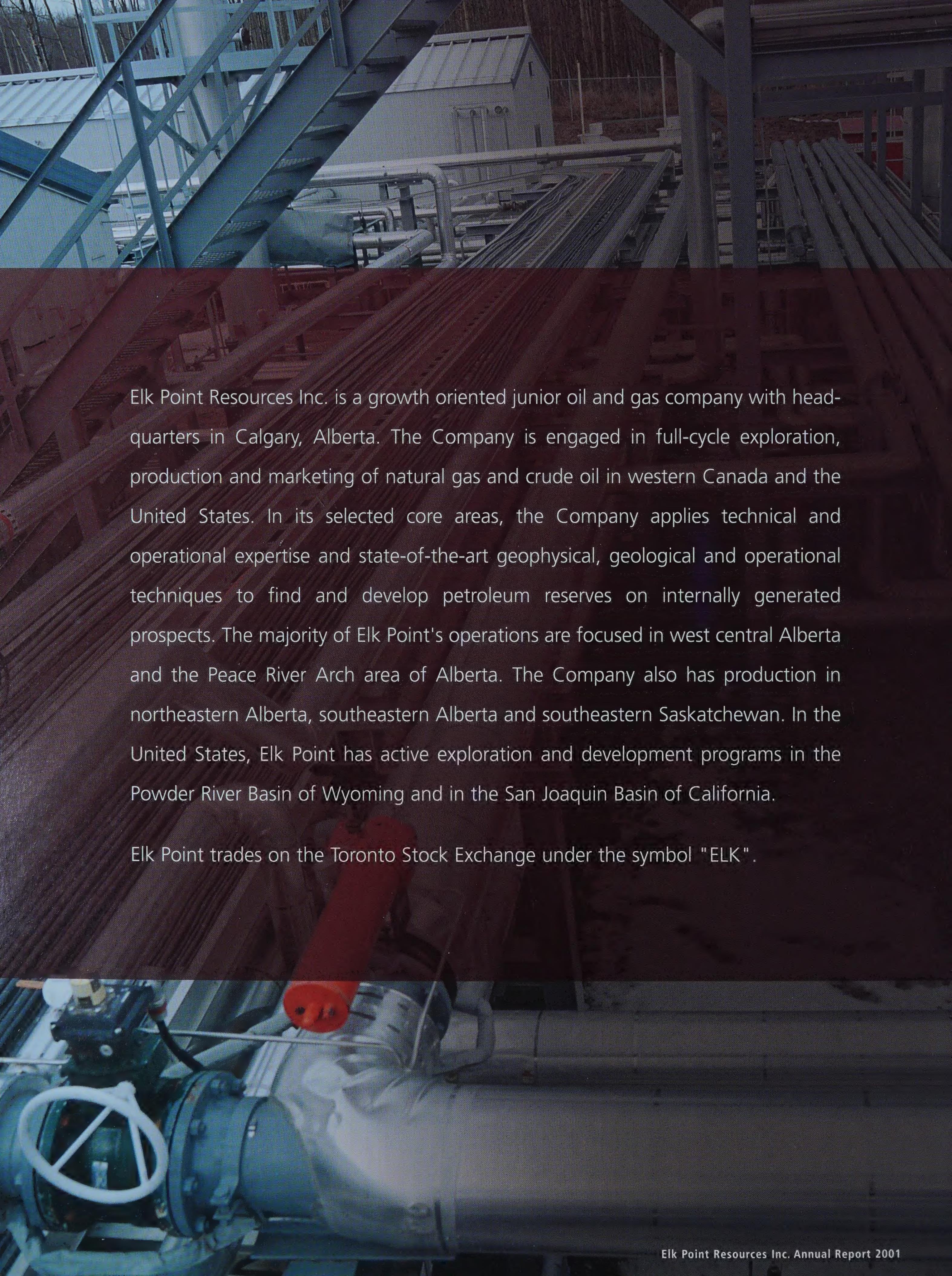


ELK POINT RESOURCES INC.

Annual Report 2001



Elk Point Resources Inc. is a growth oriented junior oil and gas company with headquarters in Calgary, Alberta. The Company is engaged in full-cycle exploration, production and marketing of natural gas and crude oil in western Canada and the United States. In its selected core areas, the Company applies technical and operational expertise and state-of-the-art geophysical, geological and operational techniques to find and develop petroleum reserves on internally generated prospects. The majority of Elk Point's operations are focused in west central Alberta and the Peace River Arch area of Alberta. The Company also has production in northeastern Alberta, southeastern Alberta and southeastern Saskatchewan. In the United States, Elk Point has active exploration and development programs in the Powder River Basin of Wyoming and in the San Joaquin Basin of California.

Elk Point trades on the Toronto Stock Exchange under the symbol "ELK".

Highlights

	2001	2000	Change
Financial ($000s, except share and per share amounts)			
Gross petroleum and natural gas revenue	$ 85,381	$ 72,358	+18%
Cash flow from operations	$ 45,164	$ 36,840	+23%
Basic per share	$ 1.60	$ 1.38	+16%
Diluted per share	$ 1.59	$ 1.38	+15%
Earnings	$ 15,789	$ 12,292	+28%
Basic per share	$ 0.57	$ 0.46	+24%
Diluted per share	$ 0.56	$ 0.46	+22%
Common Shares (weighted average for year)	28,105,965	26,600,987	+6%
Common Shares (outstanding at December 31)	29,330,164	28,002,681	+5%
Capital expenditures, net	$ 61,601	$ 60,023	+3%
Total assets	$ 280,971	$ 246,326	+14%
Working capital (deficiency)	$ (2,904)	$ 98	na
Long-term debt	$ 79,441	$ 70,768	+12%
Shareholders' equity	$ 146,625	$ 127,786	+15%
Operating			
Oil and NGLs (barrels per day)	2,473	1,884	+31%
Average price ($Cdn. per barrel)	$ 34.43	$ 35.26	-2%
Natural gas (thousand cubic feet per day)	25,353	25,937	-2%
Average price ($Cdn. per thousand cubic feet)	$ 5.88	$ 5.06	+16%
Barrels of oil equivalent per day (6:1)	6,694	6,207	+8%
Barrels of oil equivalent per day (10:1)	5,005	4,478	+12%
Undeveloped Land			
Gross acres	432,688	469,734	-8%
Net acres	195,324	209,939	-7%
Reserves			
Total proven plus probable reserves			
Oil and NGLS (thousand barrels)	15,294	14,690	+4%
Natural gas (billion cubic feet)	124.3	143.4	-13%

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AGM – The annual general meeting of shareholders will be held on Wednesday June 5, 2002 at 3:00 p.m. in the McMurray Room at the Calgary Petroleum Club, 319 – 5th Avenue S.W. Calgary. All shareholders and other interested parties are invited to attend.

Aidan Walsh, P.Eng., MBA
President and Chief Executive Officer

President's Message to Shareholders

Elk Point's cash flow from operations grew 23 percent to $45.2 million in 2001, a remarkable year which featured very high product prices over the first six months and a significant price correction in the second half of the year due to a synchronous world wide recession. Earnings were up 28 percent to $15.8 million. Highlights of 2001 included first commercial production from the Company's high impact exploration program in California, a core area acquisition of long-life producing light oil and natural gas properties at Bigoray, Lobstick, and Pembina and continued development of the Company's core properties in west central Alberta. Annual production of crude oil and natural gas liquids was up 31 percent while natural gas production was slightly lower by 2 percent.

Drilling Activity

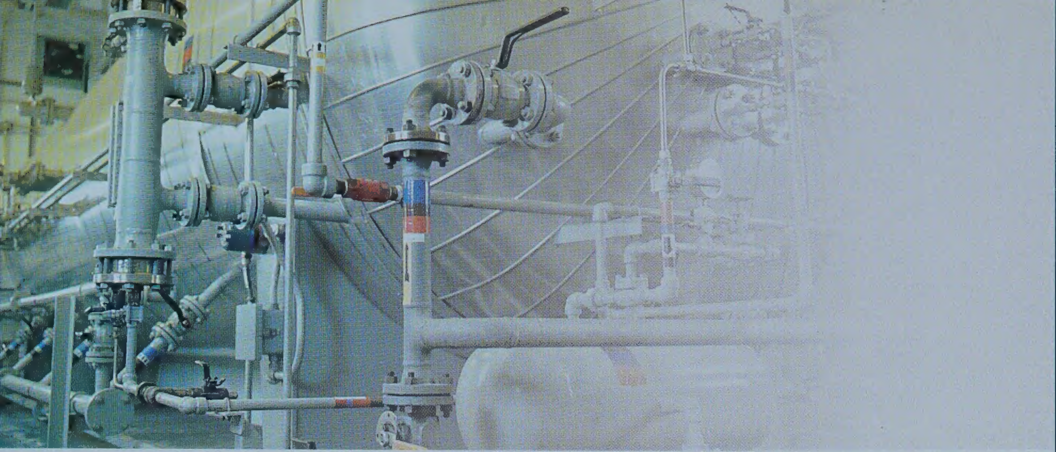
Elk Point participated in the drilling of 42 gross (23.2 net) wells, 55 percent of which were operated. The Company cased 27 gross (17.4 net) gas wells and 8 gross (1.0 net) oil wells while 7 gross (4.8 net) wells were dry and abandoned for an overall success rate of 79 percent.

Exploration and Development

In 2001, Elk Point focussed its exploration activities on multi-zone natural gas targets in west central Alberta and participated in two high impact wells at East Lost Hills in the San Joaquin Basin of California. Highlights of our drilling efforts included a commercial natural gas and condensate well at East Lost Hills, natural gas discoveries at Wildwood, Minnehik, Apetowun, Joffre and Corbett, and delineation success at Bigoray and Lobstick in west central Alberta.

In 2002, the Company's drilling program will be primarily focused on oil and natural gas properties in west central Alberta and in the Peace River Arch area of Alberta. A new coal bed methane pilot project has been initiated in west central Alberta to evaluate a potentially significant underdeveloped resource identified on Company lands. Production optimization projects in 2002 include waterflood facilities at Elcott and Boley and water disposal facilities at True Grit to optimize production from those producing oil pools. The Company also has two exploration projects identified on three-dimensional seismic targeting oil in the Powder River Basin of Wyoming.

In California, Elk Point is participating in two wells, ELH #4 and ELH #9, on the main East Lost Hills structure. The ELH #4 well reached a total depth of 20,500 feet and is currently being prepared for completion and production testing in the lower Temblor formation. The ELH #9 well has reached a total depth of 21,100 feet and is being prepared for completion and production testing. The Company anticipates that the ELH #4 and ELH #9 wells will be tested in the second quarter of 2002. Elk Point is also participating in an exploratory well which is currently being drilled on a separate prospect at Pyramid Hills. Plans are in place to drill a water disposal well and install a water injection pipeline to facilitate additional production from the producing BKP #1 well and the shut-in BKP #2 well in 2002.



Core Area Acquisition at Bigoray, Lobstick and Pembina

Elk Point closed an acquisition on May 2, 2001 for the purchase of natural gas and light crude oil assets in the Bigoray, Lobstick and Pembina areas of Alberta. The acquisition had an adjusted purchase price of $23.8 million and was funded by the Company's existing and expanded lines of credit. The acquisition included low decline oil units at Bigoray and Pembina, an operated Nisku oil pool under waterflood and increased working interests in the Bigoray and Lobstick natural gas units. Pumping equipment has been optimized and production is up 35 percent on the Nisku H pool since Elk Point took over operatorship. This was a strategic acquisition of producing properties in the Company's largest core area of west central Alberta. The acquired properties closely fit the Company's existing properties providing exploratory and operational synergies and a stable platform for future growth in this multi-zone area. The purchase of these high quality assets, which have low operating costs and an overall low decline rate, exhibits Elk Point's long-term growth strategy aiming for greater concentration in its core areas.

"A core area acquisition at Bigoray, Lobstick and Pembina further increased the Company's concentration in West Central Alberta."

Net Asset Value

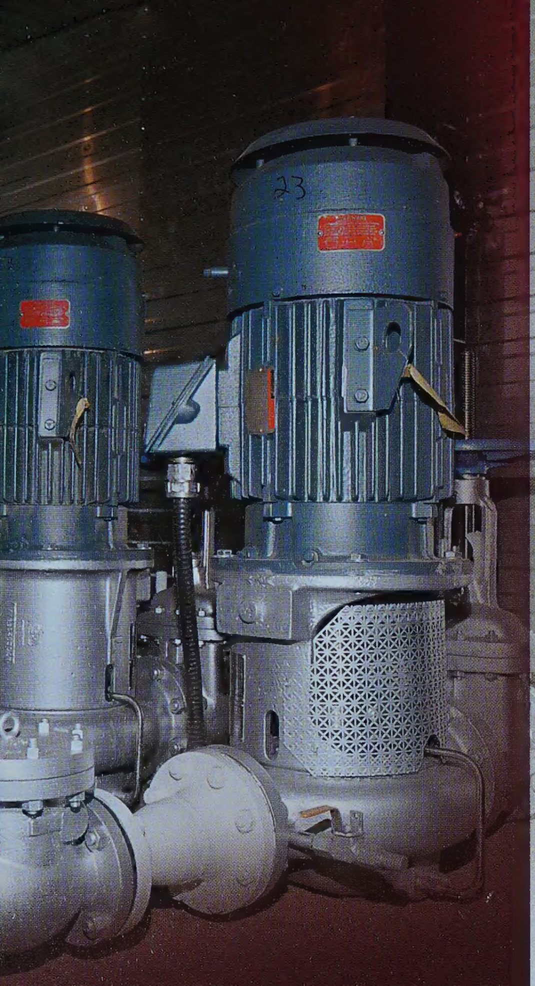
The Company's net asset value at year-end 2001, on an established reserves basis at a ten percent discount rate, was $7.54 per fully diluted share. This reflects a more conservative price forecast for both crude oil and natural gas compared to the previous year.

Reserves

In 2001, the Company added 2.76 million barrels of total proven plus probable crude oil and natural gas liquids reserves and 16.3 billion cubic feet of total proven plus probable natural gas reserves with its exploration, development and acquisition programs. Finding and developments costs before revisions were $11.68 for total reserves, $13.22 for established reserves and $15.22 for proven reserves. The Company experienced downward revisions of sixteen percent on total proven reserves and eleven percent on probable reserves due to more conservative price and production decline forecasts as well as some specific revisions due to production performance.

Liquidity and Capital Resources

In the first half of the year, the Company's debt to cash flow was very favorable, but this ratio increased over the second half of the year due to lower product prices. At December 31, 2001 the Company's debt to trailing cash flow ratio was 1.8 times. The Company is adjusting to lower commodity prices by conservatively setting its capital budget for the year at $26 million. This budget will be reviewed quarterly and may be increased if product prices and the Company's cash flow improve in the second half of 2002 as anticipated. The Company currently benefits from historically low interest rates which have reduced the Company's cost of debt considerably.



"The Company expects strong crude oil and natural gas prices over the second half of 2002."

On December 21, 2001 Elk Point completed a private placement of 1.25 million flow-through common shares at a price of $4.15 per share raising gross proceeds of $5.2 million. The gross proceeds of this offering will be used to fund the Company's natural gas and crude oil exploration activities in western Canada during 2002.

Hedging

As part of its risk management program, the Company enters into contracts to fix the sales price of its crude oil and natural gas production. At March 28, 2002, the Company had fixed the price of an annual average of 700 barrels per day of crude oil at a WTI price of U.S. $22.63 per barrel. It had also fixed the price of an annual average of 9.5 million cubic feet per day of natural gas at an AECO Hub price of Cdn. $4.63 per thousand cubic feet.

Industry Environment

The past year saw unprecedented volatility in natural gas and crude oil prices. In the first half of the year, natural gas prices soared on low inventories, increased electricity demand and increased heating demand during a cold winter. A cooler summer and a general decline in economic activity reduced demand for natural gas over the summer and US natural gas storage built at record rates. This caused a sharp decline in natural gas prices in the second half of the year and natural gas prices remained lower due to warm weather and a continued storage surplus in early 2002. Natural gas prices are expected to improve over the summer as gas supply declines and modest demand recoveries reduce both summer storage injections and the impact of higher natural gas storage.

Crude oil prices remained relatively strong in the first nine months of 2001 due to several OPEC production cuts to adjust to declining demand. However, the horrific terrorist attacks on the United States in September and the subsequent war on terrorism, combined with reduced economic activity, resulted in a significant drop in crude oil prices in the fourth quarter. The OPEC cartel recently initiated production cutbacks of 1.5 million barrels per day conditional on production cuts of approximately 0.5 million barrels per day by the non-OPEC countries of Russia, Norway, Mexico and Oman. This has stabilized and strengthened crude oil prices in the first quarter of 2002. Increased tension in the Middle East combined with anticipated recoveries in the United States and world economies will provide further support for crude oil prices over the remainder of the year.

Outlook

The East Lost Hills project is entering a more developmental phase including completions and production testing of two recently drilled exploratory wells and production optimization of the existing producing and shut-in gas wells. Capital requirements this year will be less than in previous years, yet we anticipate obtaining more information on the potential of this high pressure hydrocarbon discovery than in any previous year. Our medium-risk drilling inventory in our core areas features both natural gas and crude oil prospects in close proximity to existing infrastructure to reduce the timing of placing production onstream. A new initiative for the Company is a pilot project to evaluate highly prospective coal bed methane deposits on our lands. Elk Point is well positioned with large contiguous land holdings over this project area. Getting back to basics, the company has identified a program of recompletions and workovers on existing wellbores to achieve lower cost production additions.

Although we are entering 2002 with lower natural gas and crude oil prices, it is anticipated that both of these will improve throughout the year. Natural gas prices are expected to improve due to reduced natural gas drilling activity and increased natural gas demand as the North American economy recovers. Crude oil prices are being supported by recently announced production cutbacks by both OPEC and non-OPEC countries.

I would like to thank our shareholders for their support and the Company's Board of Directors for their continued stewardship and guidance. I would also like to acknowledge the commitment and perseverance of Elk Point's employees in the pursuit of growth opportunities for the Company. Also, the collaborative support we receive from key consultants as well as equipment and service providers is greatly appreciated.

Elk Point will continue to focus its capital expenditures mainly in west central Alberta, our largest core area, and on the delineation of the high pressure natural gas and condensate discovery at East Lost Hills in the San Joaquin Basin of California where success could translate into significant growth for the Company. Two exploration prospects targeting oil identified on three-dimensional seismic in the Powder River Basin will also be evaluated. This will be balanced with a new coal bed methane initiative and numerous property optimization opportunities in our current property portfolio. In a volatile pricing environment, we will get back to basics, be prudent in our capital commitments and continue to be guided by the principles of profitable growth and increasing shareholder value.

Respectfully submitted on behalf of the Board of Directors,

Aidan M. Walsh, P.Eng., MBA
President and Chief Executive Officer

March 28, 2002

"Getting back to basics, we will be prudent in our capital commitments and agressively pursue property optimization opportunities in our existing portfolio."

2001
Elk Point's exploration, development and acquisition activities this past year were focussed in west central Alberta and in the San Joaquin Basin of California.

2002
The Company will continue to focus in these two core areas and initiate a coal bed methane pilot project to position the Company for anticipated higher natural gas prices in the fall of 2002 and winter of 2003. The Company also has development drilling opportunities targeting natural gas and lighter crude oil in the Peace River Arch and two exploration prospects for crude oil in the Powder River Basin of Wyoming.

Major Areas of Activity

CANADA

Elk Point has focussed its operations in two core areas – west central Alberta and the Peace River Arch area of Alberta. The Company also has a mature and stable production base in three areas it has designated as harvest areas – northeastern Alberta, south-eastern Alberta and southeastern Saskatchewan. In these harvest areas, maximizing cashflow and keeping costs at a minimum are the priority.

UNITED STATES

The Company has an active exploration and development program planned in the Powder River Basin of Wyoming and is continuing its high impact drilling program in the San Joaquin Basin of California.


Peace River Arch
• Pouce Coupe
• Saddle Hills
• Valhalla
Northeastern Alberta
West Central Alberta
• Bigoray
• Thunder
• Corbett
• Wildwood
• Westerose
• Minnehik
• Lobstick
• Joffre
• Wood River
• Pembina
Southeastern Saskatchewan
Southeastern Alberta
Powder River Basin, Wyoming
San Joaquin Basin, California
• East Lost Hills
• Greater San Joaquin Basin Joint Venture

West Central Alberta Core Area

"A new initiative for the Company is a coal bed methane pilot project."

BIGORAY

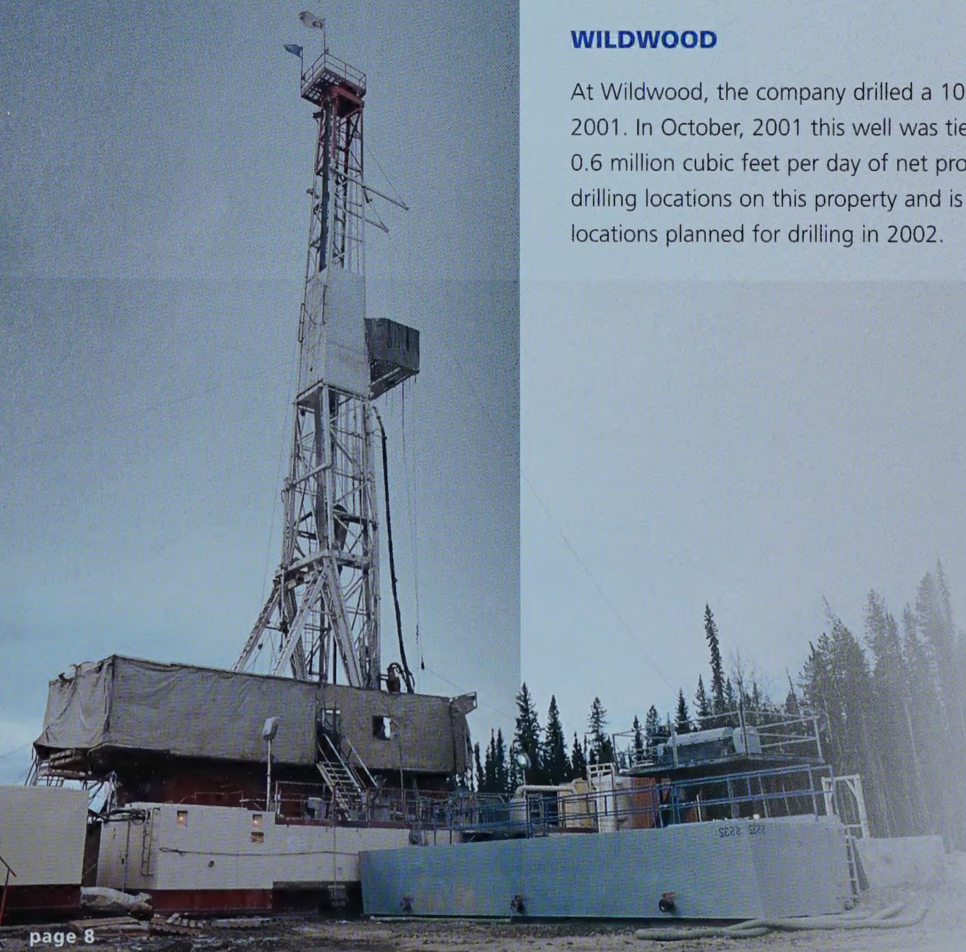
At Bigoray, the Company holds a 9.7 percent working interest in the Bigoray Unit #1 and working interests ranging up to 100 percent in offsetting non-unit lands. The Company participated in a Nordegg gas well, a Pekisko oil well and a Nisku oil well on unit lands in 2001.

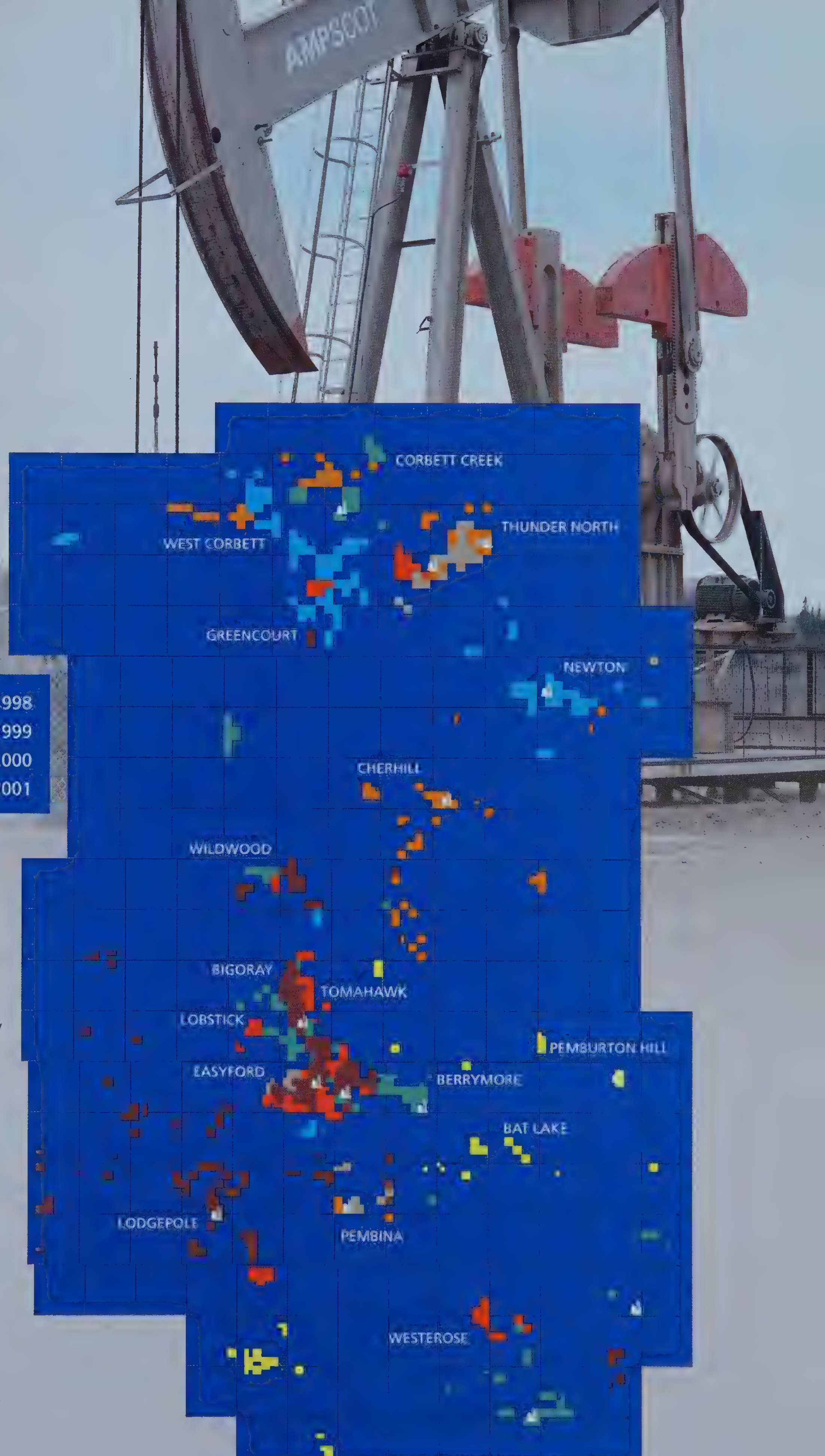
THUNDER / CORBETT CREEK

The Company has mapped and gathered technical information on coal bed methane to position itself for development of this potential long-term asset. To date, the Company has drilled two wells (100 percent working interest) targeting coal bed methane to obtain technical information and earn additional lands in its project area. The Company is also undertaking a four well pilot project in early 2002 to evaluate the gas deliverability potential from coal bed deposits on its lands in close proximity to its existing gas gathering and compression infrastructure. If this pilot project proves up commercial quantities of natural gas, it will be expanded into a commercial natural gas development project.

WILDWOOD

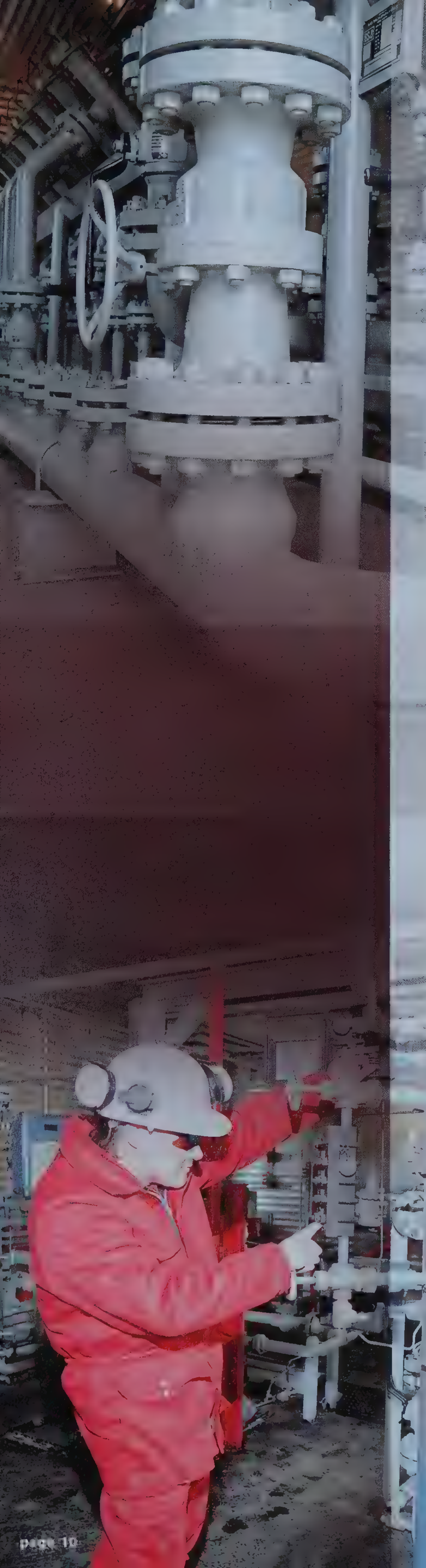
At Wildwood, the company drilled a 100 percent working interest natural gas well early in 2001. In October, 2001 this well was tied in along with a previously shut-in well adding 0.6 million cubic feet per day of net production. The Company has identified several drilling locations on this property and is currently negotiating surface access to two locations planned for drilling in 2002.





WEST CENTRAL ALBERTA

is Elk Point's largest core area with 55 percent of the Company's production base and approximately 130,000 net acres of highly prospective undeveloped lands. This area features medium depth, multi-zone targets with significant production and reserve potential from up to 15 production horizons. In 2001, the Company drilled successful gas wells at Bigoray, Joffre, Wildwood, Corbett, Bittern Lake and Minnehik.



WESTEROSE / MINNEHIK

Gas cycling facilities were installed on the Westerose Banff B oil pool in January 2001, increasing net light oil production from 15 barrels per day to 80 barrels per day. The unit participants are currently negotiating a unit expansion to include one non-unit producing well. In early 2002, the Company initiated an optimization program on its non-unit lands including recompletions, tie-ins and additional compression which is expected to add approximately 1.5 million cubic feet per day of net production by mid-year 2002.

At Minnehik, the Company drilled and cased four shallow gas wells on this property in 2001 and one in early 2002 and is currently participating in a project to tie-in two of these wells. The remaining three wells will remain shut-in until processing capacity becomes available later in 2002. Elk Point has identified two similar shallow gas projects in the Minnehik area.

LOBSTICK

Elk Point participated in the drilling of three successful Glauconite gas wells (23.1 percent working interest) in the Lobstick gas unit in 2001. Further production optimization is planned on this unit in 2002. The Company also plans to drill one exploratory Nisku well in this area.

NEWTON

The Company is planning to add a booster compressor at Newton in 2002 to increase natural gas production at this 100 percent working interest property.

JOFFRE

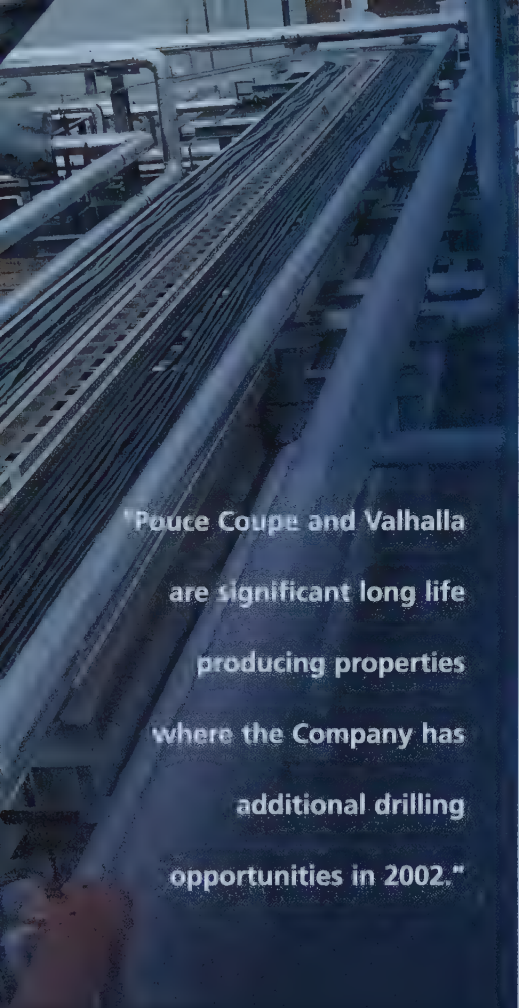
The Company drilled, cased and tied in one non-unit gas well (25 percent working interest) in August, 2001 adding 0.3 million cubic feet per day of net production. The Joffre D3A unit commenced gas blowdown in February 2002 adding 0.3 million cubic feet per day of net production. An infill drilling program at the Joffre D2 oil unit is currently being evaluated.

WOOD RIVER

Successful workovers on existing producing wells in the Wood River D2E oil unit in late 2001 have increased production from the unit by approximately 30 barrels of oil per day net to Elk Point. The Company is evaluating a recompletion on a non-unit well in 2002.

PEMBINA

At the Pembina Pekisko C Pool, the Company installed a high volume pump on one well in the pool resulting in a 22 percent increase in production. Additional recompletions and high volume pump installations are planned in 2002.



"Pouce Coupe and Valhalla are significant long life producing properties where the Company has additional drilling opportunities in 2002."

Peace River Arch Core Area

POUCE COUPE

The Pouce Coupe property is an operated, high netback, light oil property (40° API) featuring a seven percent decline rate and an average working interest of 62.8 percent. The property produces approximately 200 barrels of light oil and natural gas liquids and 0.5 million cubic feet of associated and non-associated gas. The property includes a 62.8 percent working interest in an oil battery and water injection facility, as well as amine, refrigeration and gas compression facilities. Since acquiring this waterflooded oil property in 2001, Elk Point has increased water injection rates and restored voidage replacement in the Boundary Lake reservoir from 0.8 to 1.2. This will increase reservoir pressure, improve production and enhance the ultimate oil recovery from the pool. The Company drilled one outpost location in 2001 which tested oil. The well was recently stimulated and is expected to come on stream in the second quarter of 2002 at approximately 100 barrels per day (63 barrels per day net). Two additional drilling locations have been identified.

SADDLE HILLS

The Company operates and has working interests ranging from 11 percent to 100 percent in nine producing gas wells in this area, has 70 percent ownership in a sweet gas processing plant and 30 percent ownership in a sour gas gathering and compression facility. In 2001 the Company worked over and tied in a previously shut in gas well adding 0.3 million cubic feet per day net. In 2002, the Company installed a smaller compressor at the sweet gas processing plant to effectively deplete remaining reserves and reduce operating costs.

VALHALLA

The Valhalla property is a high netback, non-operated, light oil property (37° API) with both associated and non-associated gas production. The Company's net production from this property is approximately 325 barrels per day of light oil and natural gas liquids and 2.0 million cubic feet per day of associated and non-associated natural gas. A recent waterflood pilot project in the Montney "C" pool has shown positive production response and there is an opportunity to expand the waterflood over the whole pool. This has the potential to more than double production. The Montney "I" and "O" pools are also potential waterflood candidates. The property includes a 16.33 percent working interest in an oil battery and gathering system and a solution gas compressor, as well as a 25 percent working interest in a water injection plant. Two wells in which the Company has a 25 percent working interest were placed onstream in February 2002 adding net volumes of 50 barrels per day of oil and 1.0 million cubic feet per day plus associated natural gas liquids. Several additional development drilling locations have been identified on Company lands.

The Company has 11,400 net acres of undeveloped land in this area which features multi-zone potential for oil and gas. The three main producing properties are Pouce Coupe, Valhalla and Saddle Hills.

Northeastern Alberta Area

The Company has 11,000 net acres of undeveloped land in this area. Elk Point operates three shallow gas properties at Pinehurst, Sugden and Amisk and has a non-operated property at Heart Lake. These properties generate approximately seven percent of the Company's production. The Company is negotiating the gathering of incremental production in the Sugden area into the Company's existing gas processing infrastructure which will lower our operating cost base on this property.

HEART LAKE

The Company tied in five shut-in gas wells on this property in 2001 adding net gas sales of 0.5 million cubic feet per day.

Southeastern Alberta Area

COUTTS

At Coutts in southeastern Alberta, the Company operates and has an average 45 percent working interest in a long-life, light oil property which has a central oil battery and both gas and water injection facilities.

The Company tied in three gas wells at Coutts in August 2001 which are currently producing at 0.4 million cubic feet per day net and recently tied-in 0.1 million cubic feet per day net of solution gas.

Southeastern Saskatchewan Area

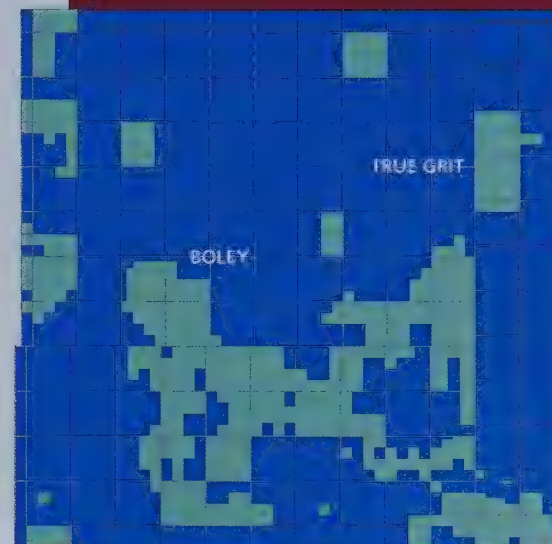
The Company holds 7,500 net acres of undeveloped land in southeastern Saskatchewan. Operated producing properties in this area account for approximately seven percent of the Company's current production. The Company operates central oil batteries and stable producing oil wells at Huntoon, West Innes and Wapella and a single well battery at Stoughton after a shut-in well was reactivated in 2001 to produce 40 barrels of oil per day net.

ELCOTT

At Elcott, a waterflood simulation study was conducted to evaluate the economic and technical feasibility of a waterflood project for this pool. The study indicated that a waterflood project, if implemented, would increase well productivity, improve the pool recovery factor and extend the reservoir life of the pool. Applications to expand water injection to two additional wells for pressure maintenance are currently being prepared. Water injection for pressure support is expected to commence in July 2002.

Powder River Basin, Wyoming

The Company has approximately 20,000 net acres of contiguous undeveloped land in the Powder River Basin targeting crude oil in the Minnelusa C sands. Production in this area is generated from the unitized oil pools at True Grit and Boley. In addition, the Company has several exploration prospects to be evaluated. Our significant land position, exploration concepts and use of three-dimensional seismic data provide us with a substantial competitive advantage and the ability to grow our production base in this area.

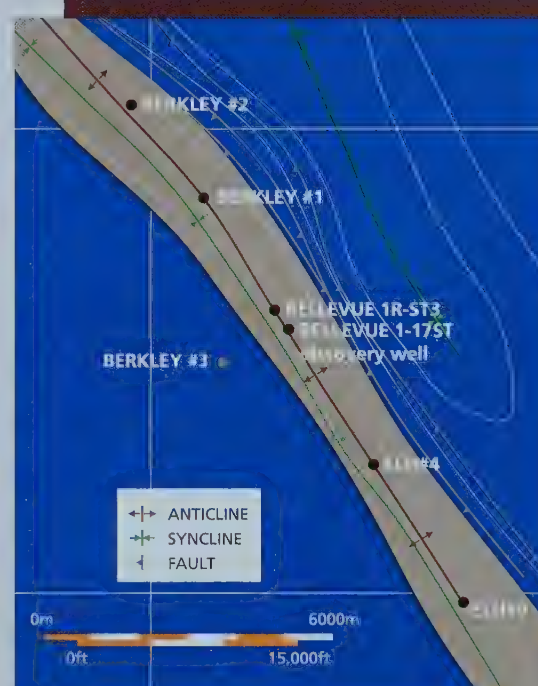


Permits are being obtained to implement a waterflood of the Boley oil pool and install a water injection system at the True Grit oil pool to increase production and recoverable reserves from both of these properties in 2002. In addition, a three dimensional seismic program undertaken in 2001 has confirmed the prospectivity of two exploratory targets for drilling in 2002.

San Joaquin Basin, California – High Impact Exploration

The Company has an interest in approximately 43,570 gross (3,027 net) acres of undeveloped land in the San Joaquin Basin.

EAST LOST HILLS



Currently, production of natural gas and associated liquids in this area is being generated from a single well, BKP #1. Two shut in wells, BKP #2 and Bellevue #1R, are capable of production and are being reviewed for tie-in. Production from the BKP #1 well is constrained due to limitations on third party water handling facilities. Plans are to drill a water disposal wells to increase water handling capacity available for the project. This will allow increased production from the BKP #1 well, and provide the necessary infrastructure to tie in both the shut-in gas wells and any additional wells which are successfully completed.

The Company is currently participating with a 7.88 percent working interest in two additional well on this prospect. The ELH #4 well reached a total depth of 20,500 feet and is currently being prepared for production testing in the lower Temblor formation. The ELH #9 well recently reached total depth of 21,100 feet. A production liner and tie-back casing string will be run on this well prior to completion and testing.

The emphasis on the East Lost Hills project in 2002 will be on completions, testing and production optimization rather than on exploration. This will generate more production additions and technical information at a lower cost than in previous years.

GREATER SAN JOAQUIN BASIN JOINT VENTURE

At Pyramid Hills, the Company is participating with a 5 percent before payout working interest in an exploration well which is currently drilling at a depth of 15,350 feet. The target depth for this exploratory test is 20,000 feet.

"Our development initiatives this year will include water injection projects at Elcott, Boley and True Grit."

Operations Review

In 2002, Elk Point will continue to develop its portfolio of natural gas and crude oil prospects and optimize its existing production base. The capital budget for 2002 has been set at $26 million. It will be reviewed quarterly and may be increased if product prices continue to improve. With greater emphasis on development this year, the Company is proceeding with a program of well recompletions to obtain lower cost production gains. At Pouce Coupe in Alberta, the Company will continue to make up voidage on the Pouce Coupe Boundary Lake oil pool through increased water injection and will continue a successful step out well drilling program. A water injection project at Elcott in southeastern Saskatchewan will be initiated to provide pressure support for that producing light oil well. In the Powder River Basin of Wyoming, water disposal facilities will be installed at True Grit to increase production from the #1 well and reactivate the #2 well, and a waterflood project will be undertaken in the Boley oil pool.

Activities in the San Joaquin Basin will have a greater emphasis on development with completions planned on two recently cased wells and a water injection well proposed to optimize gas production.

Elk Point participated in the drilling of 42 gross (23.2 net) wells, 55 percent of which were operated. The Company cased 27 gross (17.4 net) gas wells and 8 gross (1.0 net) oil wells while 7 gross (4.8 net) were dry and abandoned for an overall success rate of 79 percent.

Drilling Activity

	2001				2000			
	Exploration		Development		Exploration		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gas Wells	**22**	**16.3**	**5**	**1.1**	14	7.0	5	1.0
Oil Wells	**–**	**–**	**8**	**1.0**	4	1.8	5	3.4
Dry & Abandoned	**5**	**3.7**	**2**	**1.1**	7	3.9	6	2.2
	27	**20.0**	**15**	**3.2**	25	12.7	16	6.6

Production

Sales of crude oil and natural gas liquids increased 31 percent in 2001 to 2,473 barrels per day compared to 1,884 barrels per day in 2000. Natural gas sales were down two percent to 25.4 million cubic feet per day compared to 25.9 million cubic feet per day in 2000. Total production was up eight percent to 6,694 barrels of oil equivalent per day in 2001 from 6,207 barrels of oil equivalent per day in 2000.

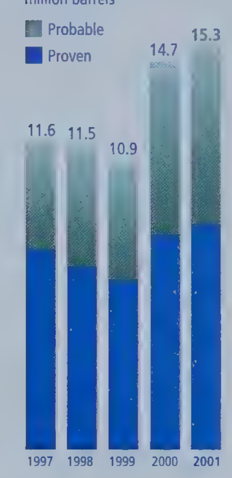
Reserve Summary

The Company's Canadian and Wyoming petroleum and natural gas reserves were independently evaluated by Reliance Engineering Group Ltd. each year for the last six years. The Company's reserves in California were independently evaluated by McDaniel and Associates Consultants Ltd. for the last two years. Below is a summary of the Company's reserves as outlined in these reports.

	Natural Gas (billion cubic feet)		Oil & NGLs (thousand barrels)	
As at December 31	**2001**	2000	**2001**	2000
Proven Developed	**72.1**	85.0	**7,524**	7,068
Proven Undeveloped	**7.1**	9.7	**997**	1,068
Total Proven	**79.2**	94.7	**8,521**	8,136
Probable	**45.1**	48.7	**6,773**	6,554
Total Proven and Probable	**124.3**	143.4	**15,294**	14,690

Crude Oil and NGL Reserves

million barrels



The price forecasts used in the Reliance Report for natural gas sales in Canada and in the McDaniels report for natural gas sales at the East Lost Hills Plant Gate effective January 1, 2002 are as follows:

Average Gas Price

($Cdn/mcf)[1]

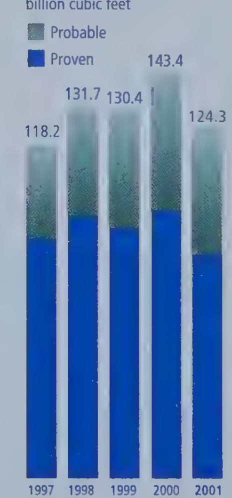
Year	TCGS[2]	Progas and PanAlberta	Spot[3]	East Lost Hills Plant Gate
2002	3.90	3.80	4.00	5.34
2003	4.22	4.35	4.35	5.61
2004	4.45	4.45	4.45	5.70
2005	4.50	4.50	4.50	5.65
2006	4.55	4.55	4.55	5.68
2007	4.60[4]	4.60[4]	4.60[4]	5.73[5]

Notes:

[1] Adjusted for Heating Value [2] TransCanada Gas Services Ltd. [3] Interruptible sales. [4] Prices escalated at 1.5 percent per year thereafter. [5] Prices escalated at 2.0 percent per year thereafter.

Natural Gas Reserves

billion cubic feet



Oil Price Schedule

Year	WTI[1] $U.S./bbl	Canadian Crude FOB Edmonton $Cdn./bbl[2]	$U.S./$Cdn. Exchange	NGL $Cdn./bbl
2002	21.50	33.60	0.625	27.70
2003	22.50	34.90	0.630	28.80
2004	23.00	35.70	0.630	29.45
2005	23.35	36.25	0.630	29.90
2006	23.70	36.80	0.630	30.75
2007[3]	24.05	37.40	0.630	31.45

Notes:

[1] West Texas Intermediate - Cushing, Oklahoma [2] 40° API and 0.5 percent sulphur adjusted for gravity and transportation. [3] Prices escalated at 1.5 percent per year thereafter.

Reconciliation of Changes in Company Working Interest Reserves

Natural Gas (billion cubic feet)	Proven	Probable	Total
Reserves December 31, 2000	94.7	48.7	143.4
Additions	11.5	4.8	16.3
Revisions to previous estimates	(17.6)	(7.6)	(25.2)
Dispositions	(0.2)	(0.8)	(1.0)
Production	(9.2)	–	(9.2)
Reserves December 31, 2001	**79.2**	**45.1**	**124.3**

Crude Oil & Natural Gas Liquids (thousand barrels)	Proven	Probable	Total
Reserves December 31, 2000	8,136	6,554	14,690
Additions	2,201	559	2,760
Revisions to previous estimates	(872)	(340)	(1,212)
Dispositions	(41)	–	(41)
Production	(903)	–	(903)
Reserves December 31, 2001	**8,521**	**6,773**	**15,294**

With net capital expenditures of $61.6 million, finding costs before revisions on a barrel of oil equivalent basis of 6:1 were $11.68 on a total reserve basis, $13.22 on an established reserve basis and $15.22 on a proven reserves basis. The Company invested $6.9 million on exploration drilling activities in California.

In 2001, Elk Point experienced downward reserve revisions of 16 percent on total proven reserves and 11 percent on probable reserves due to more conservative price and production decline forecasts. Additionally, some specific revisions due to production performance were as follows:

Easyford - production from two high volume Pekisko gas wells was lost due to a competitive drainage situation in which very high production from a competitor's well located structurally higher in the pool induced a water influx into the Company's two wells.

Pembina East - production from two Nordegg gas wells was lower than previously forecasted due to water influx.

French - a single Ostracod gas well watered out prematurely.

True Grit - reserves were downgraded due to a change in production performance. Fluid production on the high volume True Grit #1 well remained constant, but oil production declined temporarily due to water influx on this bottom water drive reservoir. Total fluid and oil production from the True Grit #1 well will be increased when the Company converts a suspended well into a water injector.

East Lost Hills - natural gas and associated liquid reserves were reduced due to lower than expected production from a single producing well for which production was constrained by the capacity of third party water handling facilities. Drilling delays resulted in insufficient new test data being gathered to obtain additional reserve bookings from the recently cased ELH #4 and ELH #9 wells. Any additional positive production and test data gained in 2002 will help to prove up additional reserves on this long-term project.

Undeveloped Land Holdings

	2001			2000		
	Acres		Average Working	Acres		Average Working
	Gross	Net	Interest	Gross	Net	Interest
Alberta	**329,467**	**163,818**	**50%**	344,120	172,119	50%
Saskatchewan	**15,081**	**7,593**	**50%**	22,956	12,384	54%
British Columbia	**3,650**	**848**	**23%**	3,665	857	23%
Manitoba	**1,080**	**360**	**33%**	1,709	570	33%
Canada	**349,278**	**172,619**	**49%**	372,450	185,930	50%
United States	**83,410**	**22,705**	**27%**	97,284	24,009	25%
Undeveloped Land	**432,688**	**195,324**	**45%**	469,734	209,939	45%

Net Asset Value

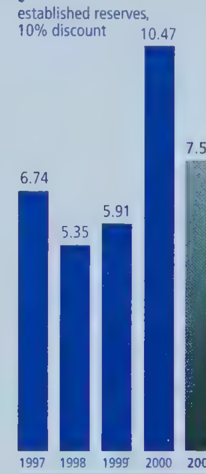
At December 31, 2001 the Company's before tax net asset value on an established reserves basis was $7.54 per share on a 10 percent discounted basis. No value is attributed to tax pools in these net asset value assessments.

Net Asset Value Calculation at December 31

($000s, except share and per share amounts)	2001	2000	1999	1998	1997
Net present value of established reserves					
(discounted at 10% before taxes)	**$ 287,066**	$ 354,675	$ 189,449	$ 166,264	$ 173,739
Undeveloped land	**17,097**	15,253	17,123	17,778	15,588
Seismic	**5,775**	5,985	5,000	5,500	5,200
Long-term debt	**(79,441)**	(70,768)	(53,328)	(71,217)	(33,586)
Working capital (deficiency)	**(2,904)**	98	(775)	(2,238)	(13,854)
Exercise of stock options and warrants	**13,656**	12,565	11,118	9,776	8,932
Total	**$ 241,249**	$ 317,808	$ 168,587	$ 125,863	$ 156,019
Fully diluted shares at December 31 (000s)	**31,995**	30,354	28,536	23,506	23,157
Established reserves					
Net asset value per fully diluted share (10%)	**$ 7.54**	$ 10.47	$ 5.91	$ 5.35	$ 6.74
Net asset value per fully diluted share (15%)	**$ 6.03**	$ 8.76	$ 4.86	$ 4.17	$ 5.65
Total Reserves					
Net asset value per fully diluted share (10%)	**$ 9.54**	$ 12.72	$ 7.07	$ 6.62	$ 7.91
Net asset value per fully diluted share (15%)	**$ 7.57**	$ 10.55	$ 5.78	$ 5.22	$ 6.59

Net Asset Value Per Share

$
established reserves, 10% discount



Included in the net present value of established reserves discounted at 10 percent before taxes is $10.1 million for the reserves in California ($7.5 million at a discount of 15 percent).

Marketing

Natural Gas

Elk Point's natural gas marketing strategy has been to increase its exposure to the Alberta spot market as the pipeline take away capacity out of the west Canadian sedimentary basin is in excess of gas supply. By year-end, natural gas sales in Alberta accounted for 90 percent of the Company's total portfolio (comprised of 82 percent in spot sales and 8 percent in fixed sales) up from 73 percent in 2000. Total sales to aggregators have been reduced to 10 percent through the expiry of some aggregator contracts, gradual quantity declines and increases in undedicated production. The Company received an average natural gas price of $5.88 per thousand cubic feet in 2001, up 16 percent from $5.06 per thousand cubic feet in 2000.

The Company also uses forward sales contracts to manage natural gas price risk. As of March 28, 2002, Elk Point had sold an annual average of 9.5 million cubic feet per day at a fixed AECO price of $4.63 per thousand cubic feet.

The Company is optimistic that North American natural gas markets will improve in 2002. Drilling activity slowed considerably in Canada and the United States in the second half of 2001 and in early 2002. Natural gas production in the United States is exhibiting overall decline in response to this decrease in drilling activity. Furthermore, there are indications of a modest recovery in the United States economy which will tend to increase natural gas demand. The combination of demand recovery and supply decline would result in lower gas storage injections and higher prices this summer and into the next heating season.

Crude Oil

In 2001, Elk Point continued to sell its crude oil and natural gas liquids under short-term contracts. By adhering to this strategy for the past several years and diligently monitoring pipeline stream differentials, the Company has optimized the netbacks on its oil and natural gas liquids sales.

The average quality of Elk Point's crude oil sales remained stable in 2001 at a light crude quality of 33° API. Elk Point's average crude oil and natural gas liquids price was Cdn. $34.43 per barrel in 2001, down from Cdn. $35.26 per barrel in 2000, a decrease of 2 percent. This compared favorably to the average price of West Texas Intermediate which declined 14 percent in 2001 to U.S. $25.90 per barrel, down from U.S. $30.20 per barrel in 2000.

Crude oil prices have stabilized and strengthened in early 2002 due to the combined 2.0 million barrels per day production cuts by OPEC and certain non-OPEC producers.

The Company's strategy includes the use of financial instruments and forward sales contracts to manage crude oil price risks. As of March 28, 2002, Elk Point had entered into forward sales contracts for an annual average of 700 barrels per day at an average WTI price of U.S. $22.63 per barrel.

Environment

The Company is aware of the risks to the environment which are inherent in its business activities. Specifically, risks include the potential pollution of air, land and water and the disruption of natural habitats. Elk Point is committed to protecting and maintaining the environment with respect to all corporate operations on behalf of shareholders, employees and the general public. The Company conducts its business in compliance with all provincial and federal operations and environmental regulations and refers to the Environmental Operating Guidelines for the Alberta Petroleum Industry as a guide.

As well, the Company has developed an Environmental Policy Statement and Management Manual which all employees and contract operators carry out their work in accordance with. Careful planning and due diligence is exercised by the Company in preparation for its field operations. By conducting its operations with the protection of the environment as a priority, the Company reduces the risks associated with its activities.

The Company has an active well abandonment and reclamation program to manage and reduce these liabilities on an ongoing basis.

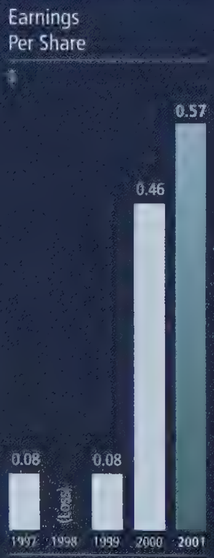
Safety

Elk Point Resources Inc. is committed to the protection of life and property in all that it seeks to achieve as an active oil and gas explorer and producer. Accordingly, our goal is to ensure the health and safety of our employees and all others involved in or impacted by our operations.

The Company has developed a Safety Policy and Corporate Safety Manual that all employees and contract operators carry out their work in accordance with. For its part, the Company will be responsible for seeking every reasonable means to provide a safe work environment; employ personnel with the skills, training and equipment required to complete their jobs in a safe manner; and use practices and procedures which meet or exceed regulatory or recognized industry standards. As well, the Company will encourage the active involvement and support of its employees in promoting and carrying out an effective safety program.

CAPP Stewardship Program

Elk Point is a member of the CAPP Environmental Health and Safety Stewardship Program, whose mission is to facilitate and enhance the sustainability of the Canadian upstream petroleum industry in a manner that equitably balances the three pillars of sustainable development: the environment, economy and society.



Management's Discussion and Analysis

The following discussion and analysis of financial results should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2001 and 2000. Readers are cautioned that information provided herein for 2002 is based on assumptions regarding future events and actual results may vary from these estimates.

All references to barrel of oil equivalent are calculated converting natural gas to oil at a ratio of six thousand cubic feet to one barrel of oil, unless otherwise indicated.

Cash Flow from Operations and Earnings

Cash flow from operations increased to $45.2 million during 2001, a 23 percent increase from $36.8 million in 2000. Cash flow per share increased to $1.60 per share in 2001, up 16 percent from $1.38 per share in 2000. Earnings increased 28 percent to $15.8 million ($0.57 per share) during 2001, up from $12.3 million ($0.46 per share) in 2000. The Company's weighted average number of shares outstanding was 28.1 million shares in 2001 compared to 26.6 million shares in 2000.

Oil and Gas Revenues

Oil and natural gas revenues increased to $85.4 million in 2001, up 18 percent from $72.4 million in 2000 due to higher natural gas prices and higher oil production.

Analysis of Change in Oil & Gas Revenues

($millions)	Gas	Oil	Total
Fiscal 2000 revenues	$ 48.1	$ 24.3	$ 72.4
Increase (decrease) in revenues due to price changes	7.7	(0.6)	7.1
Increase (decrease) in revenues due to volume changes	(1.5)	7.4	5.9
Fiscal 2001 revenues	**$ 54.3**	**$ 31.1**	**$ 85.4**

Natural gas sales continue to be the dominant contributor to revenues:			
2000 Percentage of total sales revenues	66%	34%	100%
2001 Percentage of total sales revenues	**64%**	**36%**	**100%**
2000 Percentage of total sales volumes (6:1)	70%	30%	100%
2001 Percentage of total sales volumes (6:1)	**63%**	**37%**	**100%**

Quarterly Summary Of Oil and Gas Revenues and Earnings

The following summarizes the Company's gross petroleum and natural gas revenue, earnings and earnings per share for each quarter in 2001 and 2000:

($000s, except per share amounts)	Three months ended March 31	June 30	Sept. 30	Dec. 31	Year Ended Dec. 31
2001					
Gross petroleum and natural gas revenue	**$ 30,934**	**$ 25,584**	**$ 14,918**	**$ 13,945**	**$ 85,381**
Earnings	**$ 7,853**	**$ 7,222**	**$ 1,358**	**$ (644)**	**$ 15,789**
Earnings per common share					
Basic	**$ 0.28**	**$ 0.26**	**$ 0.05**	**$ (0.02)**	**$ 0.57**
Diluted	**$ 0.28**	**$ 0.25**	**$ 0.05**	**$ (0.02)**	**$ 0.56**
2000					
Gross petroleum and natural gas revenue	$ 12,738	$ 14,504	$ 18,114	$ 27,002	$ 72,358
Earnings	$ 1,624	$ 1,659	$ 3,086	$ 5,923	$ 12,292
Earnings per common share					
Basic and diluted	$ 0.06	$ 0.06	$ 0.12	$ 0.22	$ 0.46

Netbacks

The Company's operating netback increased by 13 percent in 2001 to $22.06 per barrel of oil equivalent from $19.56 per barrel of oil equivalent in 2000.

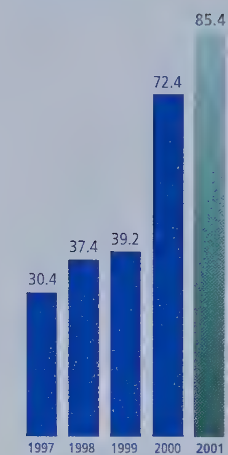
Net Back Analysis
(per barrel of oil equivalent)

	6:1 basis		10:1 basis	
Year ended December 31	**2001**	2000	**2001**	2000
Total Revenues	**$ 35.04**	$ 31.88	**$ 46.85**	$ 44.21
Royalties (net of ARTC)	**(7.80)**	(7.42)	**(10.42)**	(10.29)
Operating Costs	**(5.18)**	(4.90)	**(6.93)**	(6.80)
Operating Netback	**$ 22.06**	$ 19.56	**$ 29.50**	$ 27.12
General & Administration	**(1.31)**	(1.25)	**(1.75)**	(1.73)
Interest Expense	**(1.95)**	(1.80)	**(2.62)**	(2.50)
Capital Taxes	**(0.31)**	(0.29)	**(0.41)**	(0.41)
Cash Flow Netback	**$ 18.49**	$ 16.22	**$ 24.72**	$ 22.48

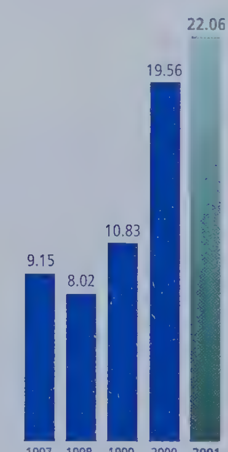
Production and Prices

	2001	2000	Change
Natural gas (thousand cubic feet per day)	**25,323**	25,937	-2%
Average price ($Cdn per thousand cubic feet)	**$ 5.88**	$ 5.06	+16%
Oil and natural gas liquids (barrels per day)	**2,473**	1,884	+31%
Average price ($Cdn per barrel)	**$ 34.43**	$ 35.26	-2%
Barrel of oil equivalent per day (6:1)	**6,694**	6,207	+8%
Barrel of oil equivalent per day (10:1)	**5,005**	4,478	+12%

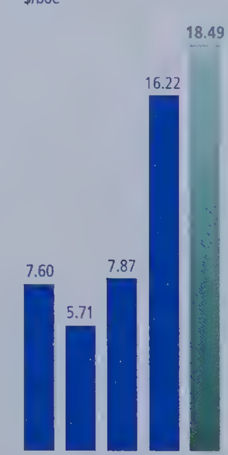
Oil & Gas Revenue
$millions



Operating Netback
$/boe

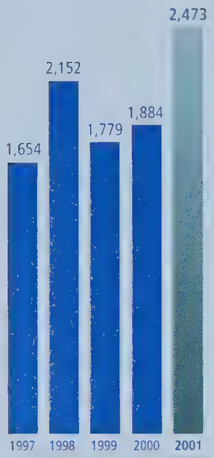


Cash Flow Netback
$/boe



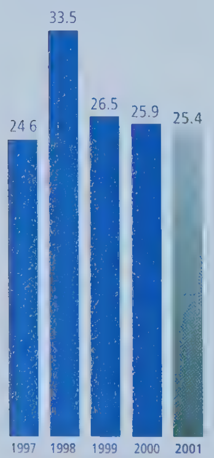
Daily Oil &
NGL Production

barrels per day



Daily Natural
Gas Production

million cubic feet per day



The Company received an average natural gas price of $3.39 per thousand cubic feet in the fourth quarter of 2001, down 57 percent from $7.96 per thousand cubic feet during the same period of 2000. The Company realized an average natural gas price of $5.88 per thousand cubic feet in 2001, up 16 percent from $5.06 per thousand cubic feet in 2000.

The Company periodically enters into gas sales agreements to provide exposure to a portfolio of pricing indices. At March 20, 2002, the Company has sales agreements in place that fix the gas sales price on an average of 5.7 million cubic feet per day of production during 2002 as follows:

Quarter	Production Volume (mmcf/d)	AECO Hub Fixed Price (Cdn.$ per mcf)
First	3.8	$ 4.28
Second	6.6	$ 4.37
Third	6.6	$ 4.37
Fourth	5.7	$ 4.46

The Company received an average crude oil and natural gas liquids price of $27.60 per barrel in the fourth quarter of 2001, down 30 percent from $39.67 per barrel for the same period in 2000. The Company realized an average crude oil and natural gas liquids sales price of $34.43 for 2001, down 2 percent from $35.26 per barrel in 2000.

The Company periodically sells its oil production through short-term sales agreements and also enters into financial instruments to hedge against a reduction in prices. At March 20, 2002, the Company entered into both physical and financial agreements which fixed the sales price on a portion of oil production during 2002 as follows:

Quarter	Production Volume Price (bbls/d)	WTI Fixed (U.S.$ per barrel)
First	134	$ 20.93
Second	792	$ 22.28
Third	687	$ 21.96
Fourth	687	$ 21.97

Royalties

Royalties net of the Alberta Royalty Tax Credit increased to $19.0 million in 2001, up from $16.9 million in 2000. As a percentage of revenue, royalties were approximately 22 percent in 2001 compared to 23 percent in 2000. The Alberta Royalty Tax Credit amounted to $0.5 million in 2001, unchanged from 2000.

Operating Expenses

Operating expenses were $12.6 million in 2001 compared to $11.1 million in 2000. On a barrel of oil equivalent basis, operating costs averaged $5.18, up from $4.90 in 2000. The increase in unit operating costs results primarily from higher industry and power costs in 2001.

General and Administrative Expenses

General and administrative expenses for 2001 increased to $3.2 million compared to $2.8 million in 2000 as a result of higher compensation expenses. On a per unit of production basis, general and administrative costs increased to $1.31 per barrel of oil equivalent in 2001 from $1.25 per barrel of oil equivalent in 2000.

Interest Expense

Interest expense increased to $4.8 million in 2001 from $4.1 million in 2000 as a result of higher average debt levels. Debt levels were higher during 2001 mainly as a result of asset acquisitions in December 2000 and May 2001. This was partially offset by lower average interest rates during the year. The Company draws upon its revolving production loan facility to partially finance development projects in its core areas.

Depletion, Depreciation and Site Restoration

The depletion and depreciation provision totaled $19.3 million in 2001 ($7.90 per barrel of oil equivalent) compared to $14.9 million ($6.61 per barrel of oil equivalent) in 2000.

A provision of $0.8 million ($0.31 per barrel of oil equivalent) was made for site restoration in 2001 compared to $0.7 million ($0.29 per barrel of oil equivalent) in 2000. The estimated future site restoration costs to be accrued over the remaining proven reserves are approximately $8.1 million.

Ceiling test calculations at December 31, 2001 for the Canadian cost center and for consolidated purposes utilized market prices at December 31, 2001. These calculations resulted in future net revenues exceeding the Company's net capitalized costs in both instances.

Ceiling test calculations for the United States cost center utilized average 2001 market prices of Cdn.$25.39 per barrel for oil, Cdn.$35.13 per barrel for natural gas liquids and Cdn.$14.82 per thousand cubic feet for natural gas. Based on these average prices, the Company's future net revenues from proven reserves exceeded the Company's net capitalized costs in the United States. Market prices at December 31, 2001 were Cdn.$14.52 per barrel for oil, Cdn.$20.91 per barrel for natural gas liquids and Cdn.$3.80 per thousand cubic feet for natural gas. Based on these year-end prices, the Company's net capitalized costs in the United States exceeded future net revenues from proven reserves by $12.2 million after-tax. This would have resulted in a pre-tax reduction in the Company's carrying value of its United States petroleum and natural gas properties of $13.1 million. Since the use of average market prices for the United States cost center resulted in future net revenues exceeding net capitalized costs, the Company did not record a reduction in the carrying value of its United States properties.

Income Taxes

Future income taxes of $9.3 million were recorded in 2001 compared to $8.9 million in 2000. Higher cash flow and profitability resulted in a higher expense in 2001. The 2001 future income tax expense is net of a $1.5 million benefit resulting from the 2 percent reduction in the Alberta corporate income tax rate effective April 1, 2001.

Current income taxes were $0.8 million in 2001 compared to $0.7 million in 2000. The Company's current income tax expense is comprised of the Federal Large Corporations Tax and the Saskatchewan Capital Tax.

All current income taxes have been deferred by the Company's tax pools which at year-end were approximately $177.3 million. These accumulated tax pools and anticipated future capital expenditures will defer current income taxes beyond 2003.

Tax Pools

December 31, 2001	Rate (%)	$ 000
Canadian Exploration Expense (CEE)	100	$ 15,740
Canadian Development Expense (CDE)	30	23,287
Canadian Oil & Gas Property Expense (COGPE)	10	61,474
Undepreciated Capital Cost (UCC)	20-30	38,977
Canadian non-capital losses and U.S. operating losses	100	25,486
U.S. depletable costs		6,353
Miscible flood deductions	100	2,648
Unamortized share issue costs	20	1,094
Earned depletion		2,251
Total Tax Pools		$ 177,310

Liquidity and Capital Resources

The Company's net capital investment in 2001 totaled $61.6 million compared to $60.0 million in 2000. The following summarizes these expenditures by major category:

	2001	2000
Exploration	**$ 17,001**	$ 15,464
Development	**8,468**	4,513
Production facilities	**8,592**	6,336
Land	**2,622**	2,341
Seismic	**767**	711
Administrative assets	**52**	35
Acquisition of P&NG assets	**24,829**	37,384
Sale of P&NG assets	**(730)**	(6,761)
	$ 61,601	$ 60,023

The Company continued to have a significant exploration focus in its 2001 capital program. Exploration, land and seismic expenditures account for over 50 percent of the Company's non-acquisition capital program. The Company invested $6.9 million in California during 2001.

On December 20, 2001, the Company completed a private placement of 1.25 million flow-through common shares at a price of $4.15 per share raising gross proceeds of $5.2 million. The gross proceeds of the offering will be used to expand the Company's exploration program in west central Alberta and the Peace River Arch area of Alberta.

At December 31, 2001, the Company had drawn $79.4 million on its revolving production loan facility. In September 2001 the Company negotiated an increase in this facility to $100 million. The Company's loan facility bears interest at the bank's prime rate or the bankers' acceptance rate plus a stamping fee.

The Company carried a working capital deficit of $2.9 million at the end of 2001. Elk Point normally has a working capital deficiency as a result of operating the majority of its projects.

Elk Point funds its ongoing exploration and development activities from internally generated funds, bank debt and the issuance of common shares. When significant oil and gas property acquisitions are evaluated, all sources of financing are considered in pursuing these incremental opportunities.

Capital Program - 2002

Elk Point has budgeted capital expenditures of $26 million in 2002 which will be allocated 35 percent towards exploration, 10 percent towards land and seismic, 40 percent towards development and investment in facilities and 15 percent towards acquisitions. The Company's exploration efforts will be focused in west central Alberta and in the Peace River Arch of Alberta. Approximately Cdn. $3 million will be expended on drilling, completions and tie-ins of deep gas wells at East Lost Hills in the San Joaquin Basin of California and Cdn. $1.5 million in the Powder River Basin of Wyoming on two water injection projects and two exploratory wells. It is anticipated that capital for exploration and development activities in 2002 will be entirely financed from internally generated funds.

Business Risks

The business of exploring for, developing, acquiring, producing and marketing crude oil and natural gas reserves is subject to many risks and uncertainties. These risks include exposure to commodity price, interest rate and foreign currency exchange rate fluctuations, safety and environmental concerns, the uncertainty of replacing annual production, the uncertainty of finding new reserves and the effects of changes in regulatory and tax legislation.

Many of these risks are not within the control of management, but the Company has adopted several strategies to reduce and minimize the effects of these factors:

- The Company employs and maintains a staff of highly motivated, qualified and experienced professionals skilled in managing these risks and uncertainties.
- The Company uses various financial instruments to manage its exposure to commodity price fluctuations.
- The Company balances its portfolio of reserves and production between natural gas and light and medium crude oil.
- The Company operates the majority of its production and drilling activities to gain greater control of costs and timing of expenditures.
- The Company focuses on selective core areas and develops technical expertise and specialized working knowledge of such areas thereby ensuring geological and operational features are well understood.
- The Company maintains an Environmental Code of Conduct which it communicates to its field operating personnel. An Emergency Response Plan is in place to expediently and efficiently deal with any operational or environmental contingencies that may arise.
- The Company has a "safety-first" policy which encourages active involvement and support of its employees in promoting and carrying out an effective safety program, and it uses practices and procedures which meet or exceed regulatory and recognized industry standards.
- The Company monitors changes in governmental regulations to ensure continued compliance.

Common Share Trading Summaries

	2001				2000			
	High	**Low**	**Close**	**Volume**	High	Low	Close	Volume
1st Quarter	**$ 5.70**	**$ 3.65**	**$ 4.80**	**6,978,336**	$ 4.00	$ 2.10	$ 3.34	4,845,957
2nd Quarter	**$ 6.10**	**$ 4.10**	**$ 4.50**	**5,561,714**	$ 5.65	$ 3.00	$ 4.00	6,859,924
3rd Quarter	**$ 5.80**	**$ 3.66**	**$ 4.25**	**7,871,245**	$ 4.33	$ 3.20	$ 3.78	2,420,102
4th Quarter	**$ 5.00**	**$ 2.60**	**$ 3.02**	**9,011,060**	$ 4.20	$ 2.80	$ 4.00	3,191,079
Year Summary	**$ 6.10**	**$ 2.60**	**$ 3.02**	**29,422,355**	$ 5.65	$ 2.10	$ 4.00	17,317,062

The Company's common shares are listed for trading on the Toronto Stock Exchange under the symbol "ELK". At March 31, 2002, the Company had 29,335,164 common shares outstanding and 2,671,051stock options outstanding at an average strike price of $4.59 per share.

Management's Report

The accompanying financial statements and all information in the annual report are the responsibility of management. The Financial statements have been prepared by management in accordance with the accounting policies described in the notes to the financial statements. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information contained elsewhere in the annual report has been reviewed to ensure consistency with that in the financial statements.

Management has developed and maintains systems of internal accounting controls, policies and procedures in order to provide reasonable assurance as to the reliability of the financial records and the safeguarding of assets.

External auditors, appointed by the shareholders of the Company, have examined the financial statements and have expressed an opinion on the statements. Their report is included with the financial statements.

The Board of Directors of the Company has established and Audit Committee, consisting of non-management directors, to review these statements with management and the auditors. The Audit Committee has approved these statements on behalf of the Company's Board of Directors.

Aidan M. Walsh
President and
Chief Executive Officer

Vivian K. L. Truesdale
Vice President, Finance and
Chief Financial Officer

March 20, 2002

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Elk Point Resources Inc. as at December 31, 2001 and 2000 and the consolidated statements of earnings, retained earnings (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2001 and 2000 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

March 20, 2002

Consolidated Balance Sheets

(thousands of dollars)

As at December 31,	2001	2000
Assets		
Current assets		
Accounts receivable	**$ 13,440**	$ 21,085
Petroleum and natural gas properties (note 2)	**267,531**	225,241
	$ 280,971	$ 246,326
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 16,344**	$ 20,987
Long-term debt (note 3)	**79,441**	70,768
Provision for site restoration	**2,969**	2,596
Future income taxes (note 6)	**35,592**	24,189
Shareholders' equity		
Share capital (note 4)	**131,827**	128,777
Retained earnings (deficit)	**14,798**	(991)
	146,625	127,786
	$ 280,971	$ 246,326

See accompanying notes to consolidated financial statements.

On behalf of the Board:

Aidan M. Walsh
Director

Peter M. S. Longcroft
Director

Consolidated Statements of Earnings

(thousands of dollars, except per share amounts)

Years ended December 31,		2001		2000
Revenues				
Petroleum and natural gas	$	85,381	$	72,358
Royalties, net of ARTC		(19,046)		(16,860)
Interest and other income		244		72
		66,579		55,570
Expenses				
Operating		12,643		11,136
General and administrative		3,208		2,829
Interest		4,810		4,097
Depletion and depreciation (note 2)		20,072		15,633
		40,733		33,695
Earnings before income taxes		25,846		21,875
Income taxes (note 6)				
Current		754		668
Future		9,303		8,915
		10,057		9,583
Earnings	$	15,789	$	12,292
Earnings per share (note 5)				
Basic	$	0.57	$	0.46
Diluted	$	0.56	$	0.46

Consolidated Statements of Retained Earnings (Deficit)

(thousands of dollars)

Years ended December 31,		2001		2000
Retained earnings (deficit), beginning of year	$	(991)	$	(3,041)
Adoption of liability method of accounting for income taxes		–		(10,242)
Earnings		15,789		12,292
Retained earnings (deficit), end of year	$	14,798	$	(991)

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

(thousands of dollars, except per share amounts)

Years ended December 31,	2001	2000
Cash provided by (used in)		
Operations		
Earnings	$ 15,789	$ 12,292
Items not affecting cash		
Depletion and depreciation	20,072	15,633
Future income taxes	9,303	8,915
Cash flow from operations	45,164	36,840
Change in non-cash working capital (note 7)	(433)	5,500
	44,731	42,340
Financing		
Long-term debt, net	8,673	17,440
Issue of common shares for cash, net of share issue costs	5,150	6,739
	13,823	24,179
Investments		
Additions to petroleum and natural gas properties and facilities	(62,331)	(66,784)
Proceeds on sale of petroleum and natural gas properties and facilities	730	6,761
Site restoration expenditures	(388)	(123)
Change in non-cash working capital (note 7)	3,435	(6,373)
	(58,554)	(66,519)
Change in cash	–	–
Cash, beginning of year	–	–
Cash, end of year	$ –	$ –
Cash flow from operations per share (note 5)		
Basic	$ 1.60	$ 1.38
Diluted	$ 1.59	$ 1.38

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

Years ended December 31, 2001 and 2000

(Tabular amounts in thousands of dollars unless otherwise indicated)

1. SIGNIFICANT ACCOUNTING POLICIES:

(a) Basis of presentation:

The consolidated financial statements of Elk Point Resources Inc. (the "Company") have been prepared by management in accordance with accounting principles generally accepted in Canada. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

The consolidated financial statements include the accounts of the Company and its wholly-owned United States subsidiary.

(b) Petroleum and natural gas properties:

The Company follows the full cost method of accounting for petroleum and natural gas properties whereby all costs relating to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs are accumulated in two cost centres, representing activities in Canada and the United States.

These capitalized costs together with production and related equipment are depleted and depreciated using the unit-of-production method based on estimated gross proved petroleum and gas reserves as determined by independent reservoir engineers. Petroleum and natural gas reserves and production are converted into equivalent units based upon relative energy content. Depreciation of facilities is charged to earnings over an estimated useful life of 20 years on a straight-line basis.

Costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

The net capitalized costs in each cost center, less salvage values, may not exceed a calculated ceiling. The ceiling is equal to the estimated undiscounted future net revenues, based on year-end prices and costs, derived from proven reserves, less the estimated development and future site restoration costs, plus the lower of cost and estimated fair value of unproven properties. Consolidated net capitalized costs are subject to a second ceiling. The consolidated ceiling is equal to the estimated undiscounted future net revenues, based on year-end prices and costs, derived from proven reserves, less the aggregate estimated development, site restoration, general and administrative, financing and income tax costs, plus the lower of cost and estimated fair value of unproven properties.

Estimated future site restoration costs are provided for over the life of the proven reserves on a unit-of-production basis. Costs are estimated each year by management based on current regulations, costs, technology and industry standards. The annual charge is included in depletion, depreciation and amortization expense and actual site restoration expenditures are charged to the accrued liability account as incurred.

Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion and depreciation.

Substantially all exploration and production activities are conducted jointly with others. Accordingly, the accounts reflect only the Company's proportionate interest in such activities.

(c) Per share amounts:

The Company follows the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments in the calculation of diluted earnings and cash flow from operations per share. Under the treasury stock method only "in-the-money" dilutive instruments impact the diluted calculation.

Basic per share amounts are computed by dividing earnings and cash flow from operations by the weighted average number of common shares outstanding for the period. Diluted per share amounts are calculated giving effect to the potential dilution that would occur if stock options or other dilutive instruments were exercised or converted to common shares. The treasury stock method assumes that any proceeds upon the exercise or conversion of dilutive instruments would be used to purchase common shares at the average market price of the common shares during the period.

(d) Future income taxes:

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized, at enacted rates, for differences between the amount reported for financial statement purposes and their respective tax basis. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in income in the period that the change occurs.

(e) Revenue recognition:

Revenues associated with the sale of natural gas, natural gas liquids and crude oil owned by the Company are recognized when title passes from the Company to its customer.

(f) Hedging:

The Company periodically enters into financial instruments and forward sales contracts to hedge its exposure to price declines on a portion of its petroleum and natural gas production. Hedge accounting is used when there is a high degree of correlation between price movements in the financial instrument and the item designated as being hedged. Gains and losses on derivative instruments used for hedging purposes are recognized in the same period as the hedged item and are recorded in the consolidated statements of earnings in the same manner as the hedged item. The fair values of derivative instruments are not recorded in the balance sheet. If correlation ceases, hedge accounting is terminated and future changes in the market value of the derivative instruments are recognized as gains and losses in the period of change.

(g) Foreign currency translation:

Accounts of foreign operations, which are considered financially and operationally integrated, are translated to Canadian dollars using average rates for the year for revenue and expenses, except depreciation and depletion which are translated at the rate of exchange applicable to the related assets. Gains or losses resulting from these translation adjustments are included in earnings. Monetary assets are translated at current exchange rates, and non-monetary assets are translated using historical rates of exchange.

(h) Flow-through shares:

The deductions for income tax purposes related to exploratory activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. The estimated tax effect of the amounts renounced to shareholders is charged to share capital with a corresponding increase in future income tax liabilities.

(i) Stock-based compensation plans:

The Company maintains one stock-based compensation plan as described in note 4. No compensation expense is recognized for this plan when stock options are issued to employees. Any consideration paid by employees upon exercise of stock options is credited to share capital.

2. PETROLEUM AND NATURAL GAS PROPERTIES:

	Cost	Accumulated depletion and depreciation	Net book value
2001			
Petroleum and natural gas properties	**$ 290,544**	**$ 85,212**	**$ 205,332**
Gas plant and well equipment	**76,088**	**13,889**	**62,199**
	$ 366,632	**$ 99,101**	**$ 267,531**
2000			
Petroleum and natural gas properties	$ 243,776	$ 69,909	$ 173,867
Gas plant and well equipment	61,255	9,881	51,374
	$ 305,031	$ 79,790	$ 225,241

In calculating the ceiling at December 31, 2001 for the Canadian cost center and for consolidated purposes, market prices at December 31, 2001 were used, and future net revenues exceeded the Company's net capitalized costs in both instances.

In calculating the ceiling for the United States cost center, market prices of Cdn.$25.39 per barrel for oil, Cdn.$35.13 per barrel for natural gas liquids and Cdn.$14.82 per thousand cubic feet for natural gas were used which are the average prices received by the Company in 2001. Based on these average prices, the Company's future net revenues from proven reserves exceeded the Company's net capitalized costs in the United States. Market prices at December 31, 2001 were Cdn.$14.52 per barrel for oil, Cdn.$20.91 per barrel for natural gas liquids and Cdn.$3.80 per thousand cubic feet for natural gas. Based on these year-end prices, the Company's net capitalized costs in the United States exceeded future net revenues from proven reserves by $12.2 million after-tax. This would have resulted in a pre-tax reduction in the Company's carrying value of its United States petroleum and natural gas properties of $13.1 million. Since the use of average market prices for the United States cost center resulted in future net revenues exceeding net capitalized costs, the Company did not record a reduction in the carrying value of its United States properties.

Costs of unproven properties excluded from costs subject to depletion and depreciation at December 31, 2001 totaled $19.5 million (2000 – $19.6 million), including $8.1 million (2000 - $8.1 million) relating to properties in the United States.

A provision for site restoration costs totaling $0.8 million (2000 – $0.7 million) is included in depletion, depreciation and amortization expense. The estimated future site restoration costs to be accrued over the remaining proven reserves are approximately $8.1 million.

At December 31, 2001, flow-through share arrangements require the Company to incur approximately $5.1 million in exploratory costs during the twelve months ended December 31, 2002.

3. LONG-TERM DEBT:

The Company borrows funds under a revolving production loan facility. Repayments of the facility are not required provided the amounts borrowed do not exceed the lesser of $100 million or an amount determined from time to time. The amount of the facility is redetermined annually by the bank and at the bank's option may be converted to a five year term facility. The next facility review is scheduled to be completed in May 2002 at which time the bank may change the amount of the facility.

The facility bears interest at the bank prime rate or the bankers' acceptance rate plus a stamping fee. Advances made under this facility are secured by a Cdn.$200 million floating charge demand debenture over the Company's interests in petroleum and natural gas properties in Canada and a U.S.$50 million floating charge mortgage and deed of trust over the Company's interests in petroleum properties in Wyoming.

4. SHARE CAPITAL:

Authorized: Unlimited number of voting common shares.

Issued:

	Number of Shares	Amount
Balance, December 31, 1999	26,530,931	$ 124,983
Issued for cash		
Exercise of stock options	71,750	135
Pursuant to flow through share issue	1,400,000	7,000
Tax effect of flow through share issue	–	(3,122)
Share issuance costs	–	(396)
Tax benefit of share issue costs	–	177
Balance, December 31, 2000	28,002,681	128,777
Issued for cash		
Exercise of stock options	77,483	222
Pursuant to flow through share issue	1,250,000	5,188
Tax effect of flow through share issue	–	(2,210)
Share issuance costs	–	(260)
Tax benefit of share issue costs	–	110
Balance, December 31, 2001	**29,330,164**	**$ 131,827**

Stock-based compensation plan:

The Company has established a stock option plan whereby certain officers, directors and employees may be granted options to purchase common shares. On December 31, 2001 there were 2,783,066 common shares reserved for issuance under the plan. The exercise price of each option equals the market price of the common shares on the date of grant. Options granted under the plan have a maximum term of five years and vest equally over a three year period starting on the first anniversary date of the grant.

A summary of the status of the plan as of December 31, 2001 and 2000 and changes during the years ending on those dates is presented below:

	2001		2000	
	Shares	**Weighted Average Exercise Price**	Shares	Weighted Average Exercise Price
Outstanding, January 1	**2,350,933**	**$ 5.34**	2,004,833	$ 5.55
Granted	**726,100**	**$ 4.29**	468,300	$ 3.95
Exercised	**(77,483)**	**$ 2.86**	(71,750)	$ 1.87
Forfeited	**(334,600)**	**$ 5.38**	(50,450)	$ 5.37
Outstanding, December 31	**2,664,950**	**$ 5.12**	2,350,933	$ 5.34
Exercisable, December 31	**1,610,300**	**$ 5.72**	1,505,700	$ 6.07

Summary information about the options outstanding at December 31, 2001 is presented below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$2.90 to $3.99	462,000	2.3 years	$ 3.12	347,334	$ 3.02
$4.00 to $4.49	903,100	4.0 years	$ 4.17	116,533	$ 4.00
$4.50 to $6.99	665,550	1.5 years	$ 5.58	512,133	$ 5.80
$7.00 to $7.65	634,300	0.7 years	$ 7.46	634,300	$ 7.46
$2.90 to $7.65	2,664,950	2.3 years	$ 5.12	1,610,300	$ 5.72

5. PER SHARE AMOUNTS:

The weighted average number of shares outstanding during the year was 28,105,965 (2000 – 26,600,987). In computing diluted earnings per share and cash flow from operations per share, 226,485 shares (2000 – 110,730 shares) were added to the weighted average number of common shares outstanding during the year for the dilutive effect of stock options.

6. INCOME TAXES:

Effective January 1, 2000, the Company adopted the liability method of accounting for income taxes without restatement of prior years. As a result, both the future income tax liability and deficit were increased by $10,242 on that date.

The provision for income taxes varies from the amounts that would be computed by applying the statutory federal and provincial income tax rates of 42.6% (2000 – 44.6%) to earnings before income taxes. Income taxes have been computed as follows:

	2001	2000
Computed "expected" tax provision	**$ 11,011**	$ 9,756
Crown royalties	**6,584**	5,804
Resource allowance	**(6,425)**	(5,714)
Alberta royalty tax credit	**(213)**	(230)
U.S. tax rate difference	**(116)**	(145)
Reduction in Alberta provincial tax rate	**(1,538)**	-
Other	**-**	(556)
Capital taxes - Canada	**754**	668
	$ 10,057	$ 9,583

The components of the Company's net future income tax liability at December 31, 2001 and 2000 are as follows:

	2001	2000
Future income tax assets		
Non-capital losses – Canada	$ 4,297	$ 4,498
– United States	5,847	4,534
Future site restoration	935	869
Share issue costs	466	659
Other	2,077	2,126
Future income tax liabilities		
Petroleum and natural gas properties in excess of tax values	(49,214)	(36,875)
	$ (35,592)	$ (24,189)

7. CASH FLOW INFORMATION:

	2001	2000
Change in balance sheet amount		
Accounts receivable	$ 7,645	$ (8,707)
Accounts payable and accrued liabilities	(4,643)	7,834
	$ 3,002	$ (873)
Change in non-cash working capital		
Operations	$ (433)	$ 5,500
Investments	3,435	(6,373)
	$ 3,002	$ (873)

The following cash payments were made during the year:

	2001	2000
Interest paid	$ 4,836	$ 3,899
Taxes paid	$ 745	$ 494

8. FINANCIAL INSTRUMENTS:

The Company is exposed to fluctuations in commodity prices, interest rates and exchange rates. The Company monitors these risks and periodically utilizes financial instruments to manage its exposure to these risks.

Commodity price risk management

(a) Natural Gas

The Company enters into gas sales agreements to provide exposure to a portfolio of pricing indices. At December 31, 2001, the Company has sales agreements in place that fixed the gas sales price on 3.5 million cubic feet per day of production during 2002 as follows:

Quarter	Production Volume (mmcf/d)	AECO Hub Fixed Price (Cdn.$ per mcf)
First	3.8	$ 4.28
Second	3.8	$ 4.21
Third	3.8	$ 4.21
Fourth	2.5	$ 4.03

(b) Crude Oil

The Company sells its oil production through short-term sales agreements and also enters into financial instruments to hedge against a reduction in prices. At December 31, 2001, the Company had no agreements in place which fixed the sales price on its oil production.

Foreign currency risk management

The Company is exposed to foreign currency fluctuations on its United States operating activities as these activities are denominated in U.S. dollars. At December 31, 2001 there were no contracts in place to fix exchange rates on these transactions.

Interest rate risk management

At December 31, 2001 the Company had $79.4 million of variable rate debt. There were no contracts in place at December 31, 2001 to fix the interest rate on this floating rate debt.

Credit risk

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risk. Purchasers of the Company's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

The Company is also exposed to credit risk associated with possible non-performance by financial instrument counterparties. In an effort to minimize credit risk, it is the Company's practice to only enter into financial arrangements with established counterparties who have an investment grade credit rating, as determined by recognized credit rating agencies.

Fair values

The carrying amounts of the Company's financial assets and liabilities approximate their fair values as at December 31, 2001.

9. SEGMENT INFORMATION:

2001 Operating and Geographic Segments

	Canada	United States	Total
Revenues			
Petroleum and natural gas	**$ 81,916**	**$ 3,465**	**$ 85,381**
Royalties, net of ARTC	**(18,255)**	**(791)**	**(19,046)**
	$ 63,661	**$ 2,674**	**$ 66,335**
Petroleum and natural gas properties			
Cost	**$ 339,929**	**$ 26,703**	**$ 366,632**
Accumulated depletion, depreciation and amortization	**(97,980)**	**(1,121)**	**(99,101)**
	$ 241,949	**$ 25,582**	**$ 267,531**

2000 Operating and Geographic Segments

	Canada	United States	Total
Revenues			
Petroleum and natural gas	$ 70,033	$ 2,325	$ 72,358
Royalties, net of ARTC	(16,092)	(768)	(16,860)
	$ 53,941	$ 1,557	$ 55,498
Petroleum and natural gas properties			
Cost	$ 285,712	$ 19,319	$ 305,031
Accumulated depletion, depreciation and amortization	(79,636)	(154)	(79,790)
	$ 206,076	$ 19,165	$ 225,241

STATISTICAL SUMMARY

	2001	2000	1999	1998	1997	1996	1995
Financial ($000s, except share and per share amounts)							
Gross petroleum and natural gas revenue	**$ 85,381**	$ 72,358	$ 39,210	$ 37,444	$ 30,418	$ 15,324	$ 4,767
Cash flow from operations	**$ 45,164**	$ 36,840	$ 17,798	$ 16,116	$ 15,965	$ 8,971	$ 2,114
Per share - basic	**$ 1.60**	$ 1.38	$ 0.77	$ 0.74	$ 0.91	$ 0.96	$ 0.32
Earnings	**$ 15,789**	$ 12,292	$ 1,897	$ (8,886)	$ 1,350	$ 2,554	$ 369
Per share - basic	**$ 0.57**	$ 0.46	$ 0.08	$ (0.41)	$ 0.08	$ 0.27	$ 0.04
Per share - diluted	**$ 0.56**	$ 0.46	$ 0.08	$ (0.41)	$ 0.08	$ 0.26	$ 0.04
Number of Common Shares							
Outstanding at December 31 (000s)	**29,330**	28,003	26,530	21,716	21,629	14,009	8,229
Weighted average for year (000s)	**28,106**	26,601	23,109	21,686	17,481	9,333	6,568
Shareholders' equity	**$ 146,625**	$ 127,786	$ 121,942	$ 97,787	$ 106,594	$ 45,307	$ 11,168
Capital expenditures, net	**$ 61,601**	$ 60,023	$ 22,452	$ 42,135	$ 112,903	$ 44,838	$ 7,711
Total assets	**$ 280,971**	$ 246,326	$ 192,568	$ 190,935	$ 182,889	$ 67,266	$ 19,286
Working capital deficiency	**$ (2,904)**	$ 98	$ (775)	$ (2,238)	$ (13,854)	$ (3,924)	$ (1,333)
Long-term debt	**$ 79,441**	$ 70,768	$ 53,328	$ 71,217	$ 33,586	$ 5,750	$ 4,055
Operations							
Crude oil and NGL production (bbls/d)	**2,473**	1,884	1,779	2,152	1,654	1,047	123
Average sales price ($/bbl)	**$ 34.43**	$ 35.26	$ 22.33	$ 16.83	$ 23.57	$ 26.76	$ 21.44
Natural gas production (mcf/d)	**25,323**	25,937	26,499	33,454	24,632	7,373	6,876
Average sales price ($/mcf)	**$ 5.88**	$ 5.06	$ 2.55	$ 1.98	$ 1.80	$ 1.77	$ 1.35
Barrels of oil equivalent at 6:1							
Total daily production (boe/d)	**6,694**	6,207	6,196	7,728	5,759	2,276	1,269
Operating netbacks ($/boe)	**$ 22.06**	$ 19.56	$ 10.83	$ 8.02	$ 9.15	$ 12.74	$ 6.76
Operating costs ($/boe)	**$ 5.18**	$ 4.90	$ 4.27	$ 3.47	$ 3.32	$ 4.31	$ 2.68
General and administrative costs ($/boe)	**$ 1.31**	$ 1.25	$ 1.13	$ 0.92	$ 0.89	$ 1.01	$ 1.54
Barrels of oil equivalent at 10:1							
Total daily production (boe/d)	**5,005**	4,478	4,429	5,497	4,117	1,784	811
Operating netbacks ($/boe)	**$ 29.50**	$ 27.12	$ 15.14	$ 11.28	$ 12.79	$ 16.25	$ 10.57
Operating costs ($/boe)	**$ 6.93**	$ 6.80	$ 5.97	$ 4.88	$ 4.64	$ 5.50	$ 4.20
General and administrative costs ($/boe)	**$ 1.75**	$ 1.73	$ 1.58	$ 1.30	$ 1.25	$ 1.29	$ 2.40
Reserves							
Crude oil and NGLs (Mbbls)							
Proven	**8,521**	8,136	6,405	6,924	7,558	2,813	941
Probable	**6,773**	6,554	4,508	4,601	4,077	757	611
Total	**15,294**	14,690	10,913	11,525	11,635	3,570	1,552
Natural gas (Bcf)							
Proven	**79.2**	94.7	88.6	93.2	84.8	45.0	19.8
Probable	**45.1**	48.7	41.8	38.5	33.4	11.3	4.4
Total	**124.3**	143.4	130.4	131.7	118.2	56.3	24.2
Wells Drilled							
Gross	**42**	41	32	79	100	43	21
Net	**23.2**	19.3	17.0	46.6	59.3	28.9	12.7
Land Holdings							
Gross acres	**432,688**	469,734	554,762	583,856	506,691	313,379	236,218
Net acres	**195,324**	209,939	247,846	263,594	226,054	130,219	77,811

OUR TEAM

Wayne Astill
Laura Bateman
Troy Brazzoni
Maureen Bryne
Garth Buchholz
Shelley Cooper
Darrin Drall
Scott Dyck
Jay Forbes
Brain Goodfellow
Lisa Greening
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Suzanne Linklater
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Chantel Rusnak
Jason Schoenfeld
Cathy Strange
Brad Taylor
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Cathy Veness
Richard Wade
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Kari Webb

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President
Reston Resources Ltd.

Peter M. S. Longcroft(1)(2)
Chairman
Sterling Capital Group Ltd.

Rodger A. Tourigny(1)(2)
President
Tourigny Management Ltd.

Aidan M. Walsh(2)(3)
President & Chief Executive Officer
Elk Point Resources Inc.

(1) Member of Audit Committee
(2) Member of Compensation Committee
(3) Member of Corporate Governance Committee

MANAGEMENT AND OFFICERS

Troy K. Brazzoni
Executive Vice President, Exploration

Darrin R. Drall
Vice President, Corporate Development

Scott R. Dyck
Controller

Brian J. Goodfellow
Vice President, Production and Operations

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Vice President, Land

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Vice President, Finance & Chief Financial Officer

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President & Chief Executive Officer

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ENGINEERING

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STOCK EXCHANGE LISTING

The Toronto Stock Exchange
Trading Symbol: ELK

Visit us at our website: www.elkpointresources.ca

ABBREVIATIONS

bbls	Barrels
bbls/d	Barrels per day
mbbls	Thousand barrels
mcf	Thousand cubic feet
mcf/d	Thousand cubic feet per day
mmcf	Million cubic feet
mmcf/d	Million cubic feet per day
bcf	Billion cubic feet
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
AEUB	Alberta Energy and Utilities Board
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
GPP	Good Production Practice
OPEC	Organization of Petroleum Exporting Countries
WTI	West Texas Intermediate

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